SHELL OIL PRODUCTS US

BAKERSFIELD PLANT

INJECTION WELL "RED RIBBON" WD-1

STEP RATE TEST

NOVEMBER 15 – 17, 2004

Prepared by

PRC PETROtech Resources Company

INTRODUCTION

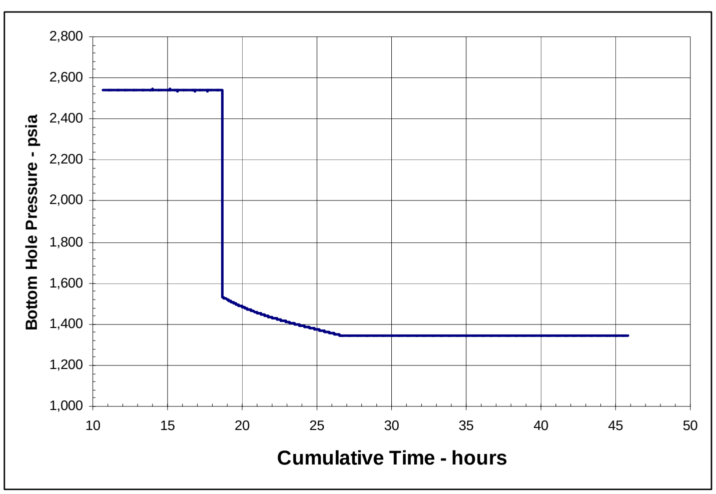
The Shell Oil Products US Bakersfield Refinery is located at 6451 Rosedale Highway, Bakersfield, California. The subject injection well, “Red Ribbon” WD-1, is located 1716’ south and 131’ east of the northwest corner of Section 27, Township 29S, Range 27E. Specific testing was performed on the well November 15 to 17, 2004 in an attempt to determine the fracture gradient of the target injection zone. Mr. George Robin of the Environmental Protection Agency witnessed the testing.

WELL CONDITION

Exhibit 1 contains a well completion diagram. The well is perforated in the Pliocene aged “Mason” and “Parker” zones of the Chanac formation of the Fruitvale Oil Field. There are 125’ of net perforations across a 190’ gross interval. The well is completed with a combination tubing string and a packer set directly above the injection interval.

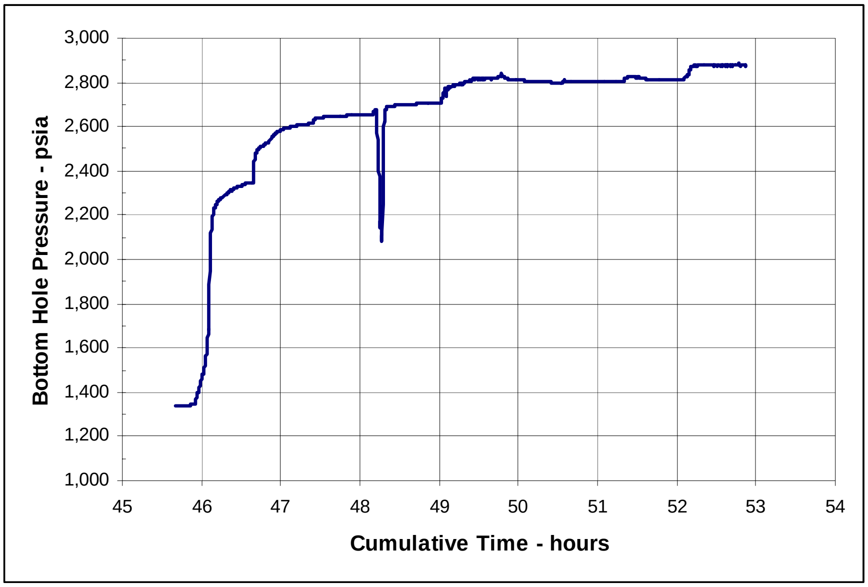
PRESSURE FALL-OFF TEST

On November 15, two high resolution pressure recorders were installed in the well at a depth of 3505’ (top perforation depth). The well remained on injection until 8:00 a.m. November 16, at which time it was shut down in order to obtain the static reservoir pressure. After 27 hours shut down, the static bottom-hole pressure was 1,342 psia and is considered to be the current average static reservoir pressure at that depth.



STEP RATE TEST

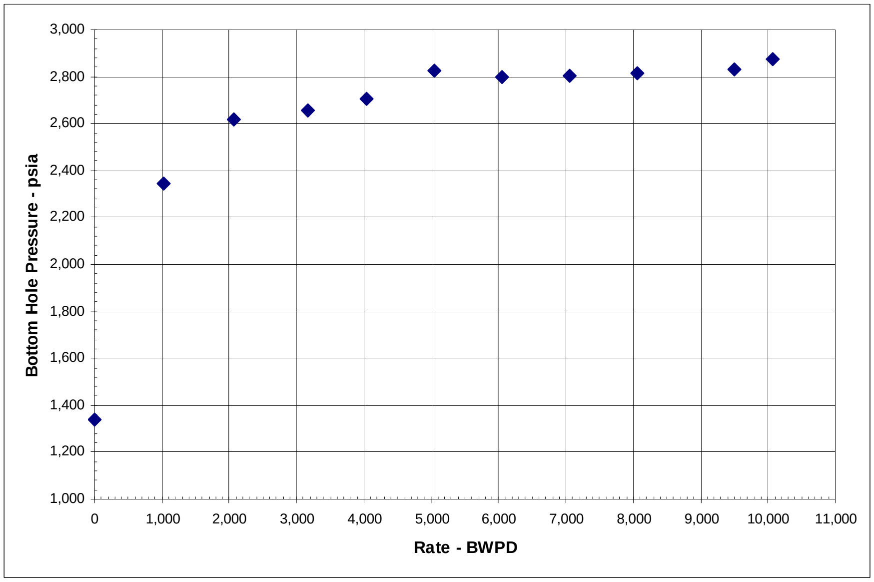
The step rate test was conducted on November 17, starting at 11:10 a.m. using a portable pump truck. Step rate increments of approximately 1,000 bbls per day were used in 45 minute intervals, from an initial rate of 0 bbls per day up to a final rate of 10,080 bbls per day. The bottom-hole pressure data is shown below. The rapid pressure drop at 48.25 hours reflects a temporary problem experienced with the surface pumping equipment.



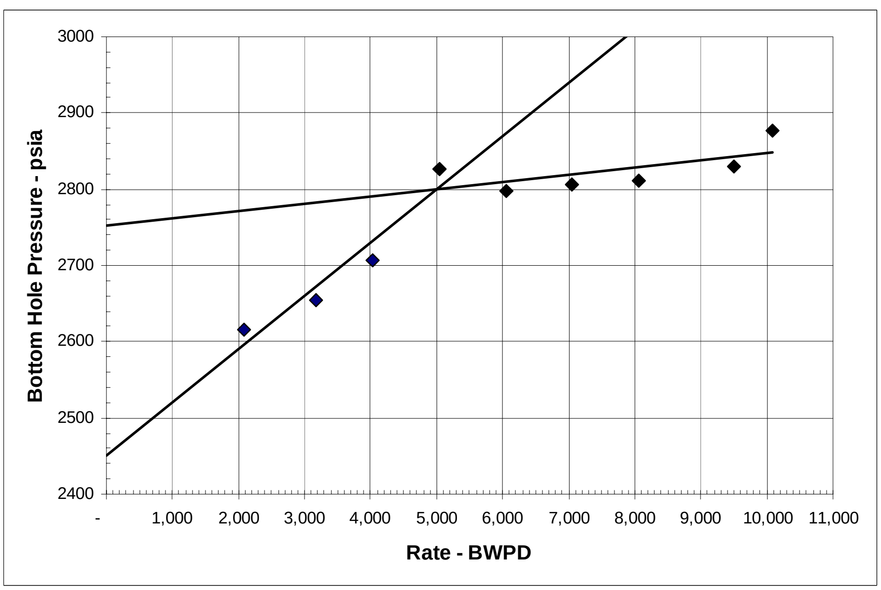
The final stabilized bottom hole pressure (BHP) at the end of each step rate (BPD) was as follows:

Rate BPD	BHP
0	1,341
1,022	2,343
2,074	2,615
3,168	2,654
4,032	2,706
5,040	2,826
6,048	2,798
7,056	2,806
8,064	2,812
9,504	2,830
10,080	2,877

The first two data points appear to be non-linear and are interpreted to be a result of wellbore storage effects prior to achieving “steady-state” flow conditions and reservoir “fill-up”.



The formation fracture pressure gradient was determined using the generally accepted method of analyzing the relationship between the downhole pressure and injection rate. When the bottom hole pressure exceeds the formation fracture pressure, the newly induced fracture provides an increased flow capacity to the reservoir. The newly induced fracture changes the relationship between rate and pressure.



The bottom hole pressure corresponding to the point at which the two trend lines intersect is 2,800 psia and is interpreted to be the bottom hole fracture pressure. Extrapolation of the second line's slope back to the Y axis shows a pressure of 2,750 psia. This pressure is much greater than the initial pre-test reservoir pressure of 1,342 psia indicating that the pressure points along the second line are above the fracture pressure.

Exhibit 2 is a plot of the bottom hole pressure for the entire testing period.

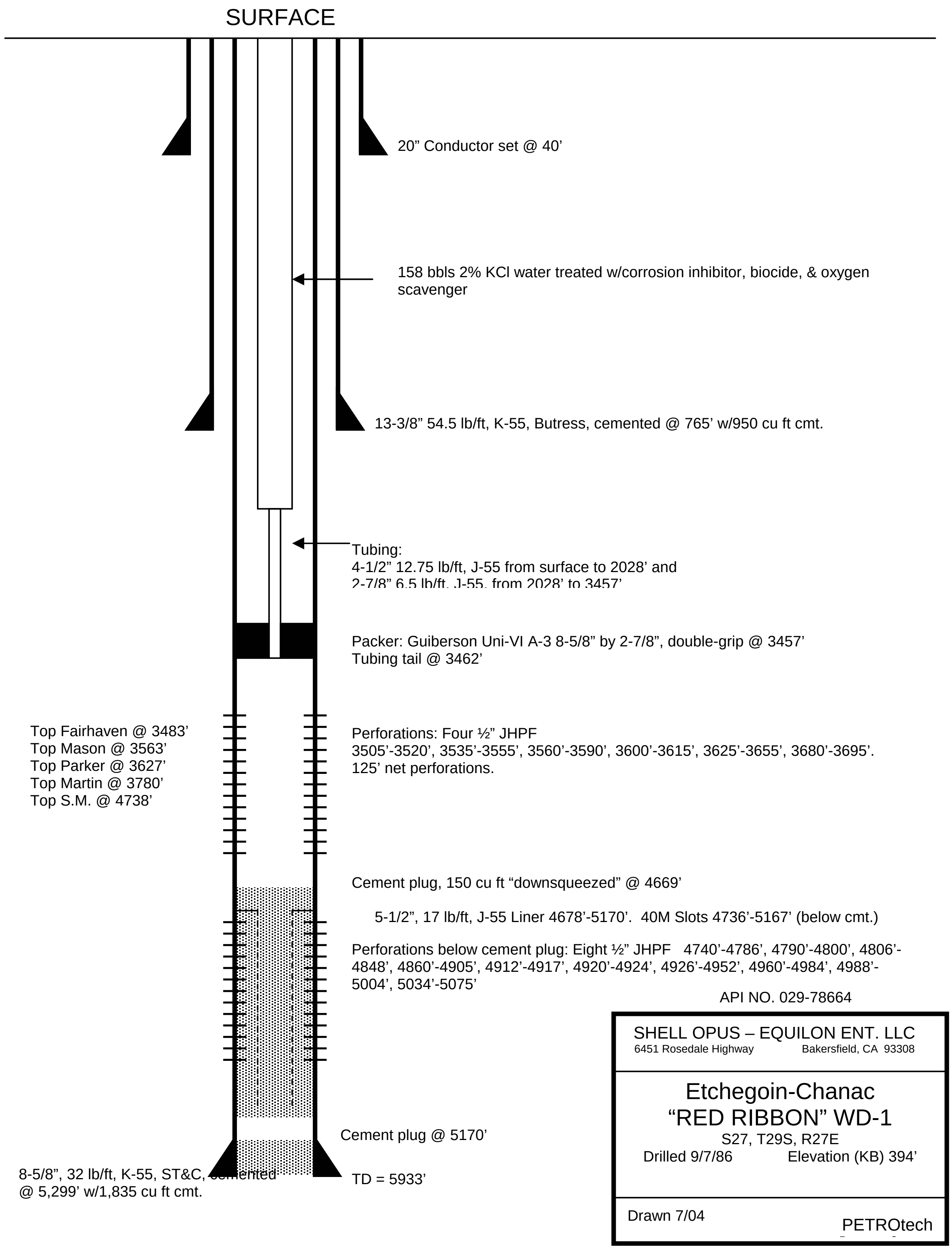
CONCLUSION

The calculated bottom hole fracture gradient for the well is 0.80 psia/ft (2500 psia / 3505 ft) and is consistent with the value recognized by the California Division of Oil, Gas, and Geothermal Resources for the southern San Joaquin Valley.

____ **Date:** _______________

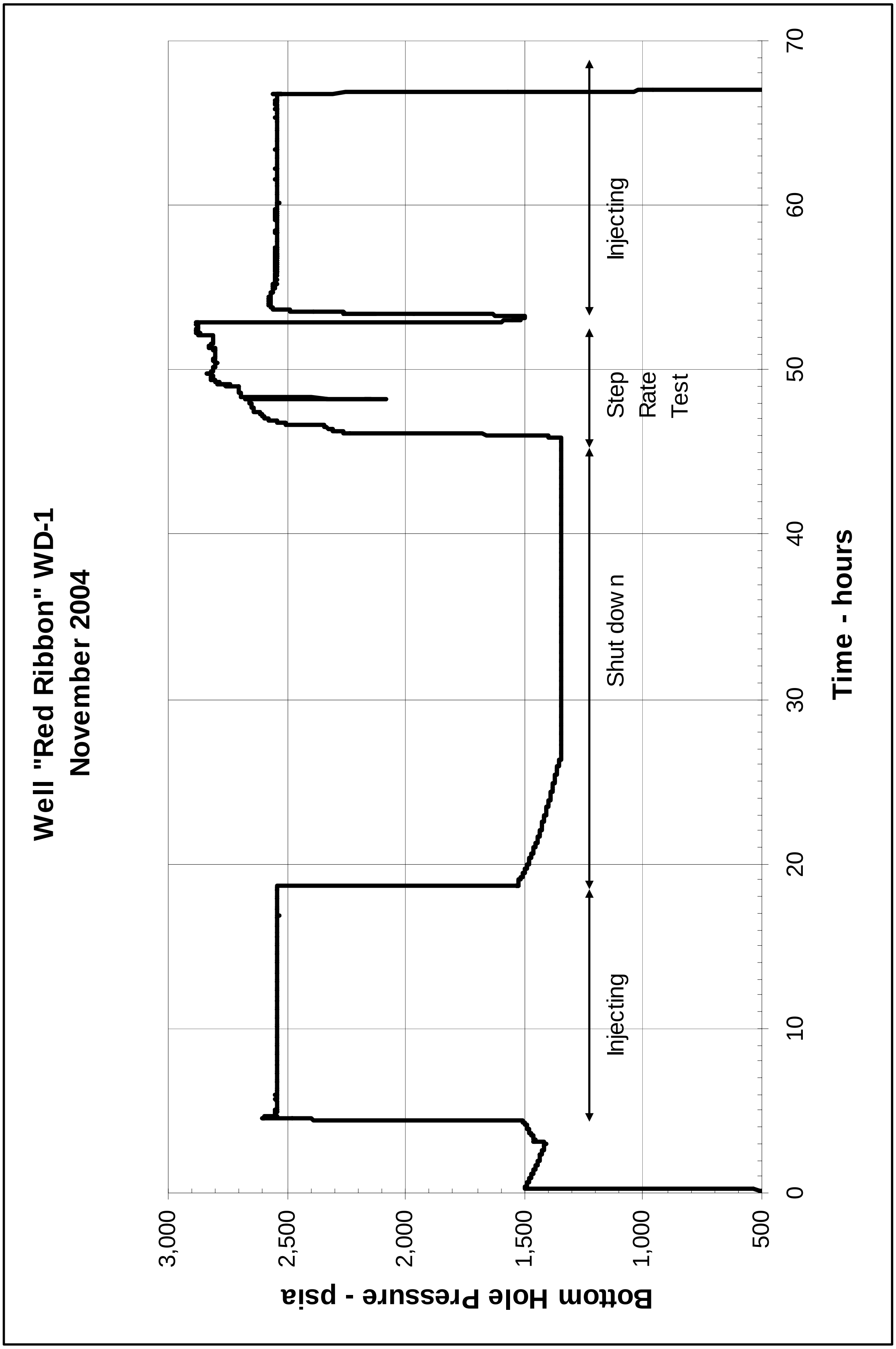
Bradford A. DeWitt
P.E. #P1804
State of California

EXHIBIT 1



NOTE: Not drawn to scale.

EXHIBIT 2


Well "Red Ribbon" WD-1
November 2004
Bottom Hole Pressure - psia
3,000
2,500
2,000
1,500
1,000
500
0
10
20
30
40
50
60
70
Time - hours
Injecting
Shut down
Step
Rate
Test
Injecting

Step Rate Test – Additional Information
Correlation of Surface and Bottom-Hole Pressures and Rate

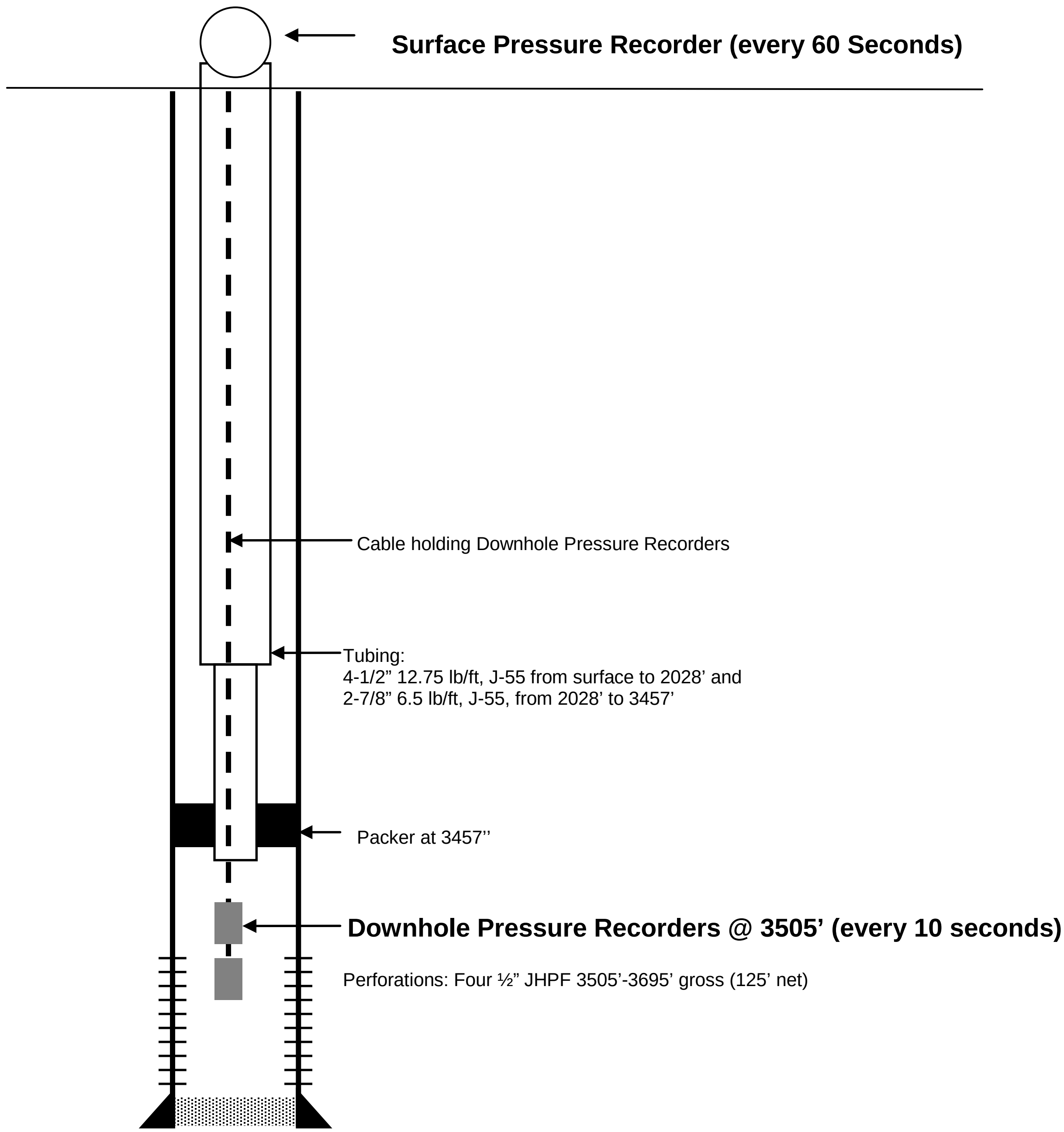
Additional information and analysis relative to the November 2004 Step Rate Test on well "Red Ribbon" WD-1 was requested by the EPA via email on February 26, 2008 and further discussed via teleconference on February 28, 2008.

Additional information was requested relative to friction pressure loss measurements; correlation of surface and bottom-hole pressure measurements; and demonstration of historic injection performance below fracture pressures.

As part of the Step Rate Test two high resolution pressure recorders were installed in the well at a depth of 3505' (top perforation depth). These instruments recorded the Bottom-Hole pressure at time increments of every 10 seconds. These instruments did not have a surface readout and therefore had to be retrieved from the well to obtain the pressure data recorded during the test. The wellhead had previously been equipped with continuous pressure monitoring instruments which recorded the surface wellhead pressure at time increments of every 60 seconds.

Well Schematic and location of Surface and Bottom-Hole Pressure Recorders

Below is a simple schematic of the wellbore condition at the time of the Step Rate Test and the location of the pressure recorders:



Correction for Hydrostatic Head

Due to the design limitations of the refinery pumping equipment a large portable pump was used for the test. The test used “finished” refinery injection water. The most recent analysis available indicated the finished water had a specific gravity of 1.061 at 60^{O}F . No attempt was made to correct the density for temperature as bottom-hole temperature during the test was about 102^{O}F constant. This specific gravity was used to establish the hydrostatic head pressure difference between the surface and bottom-hole recorders as follows:

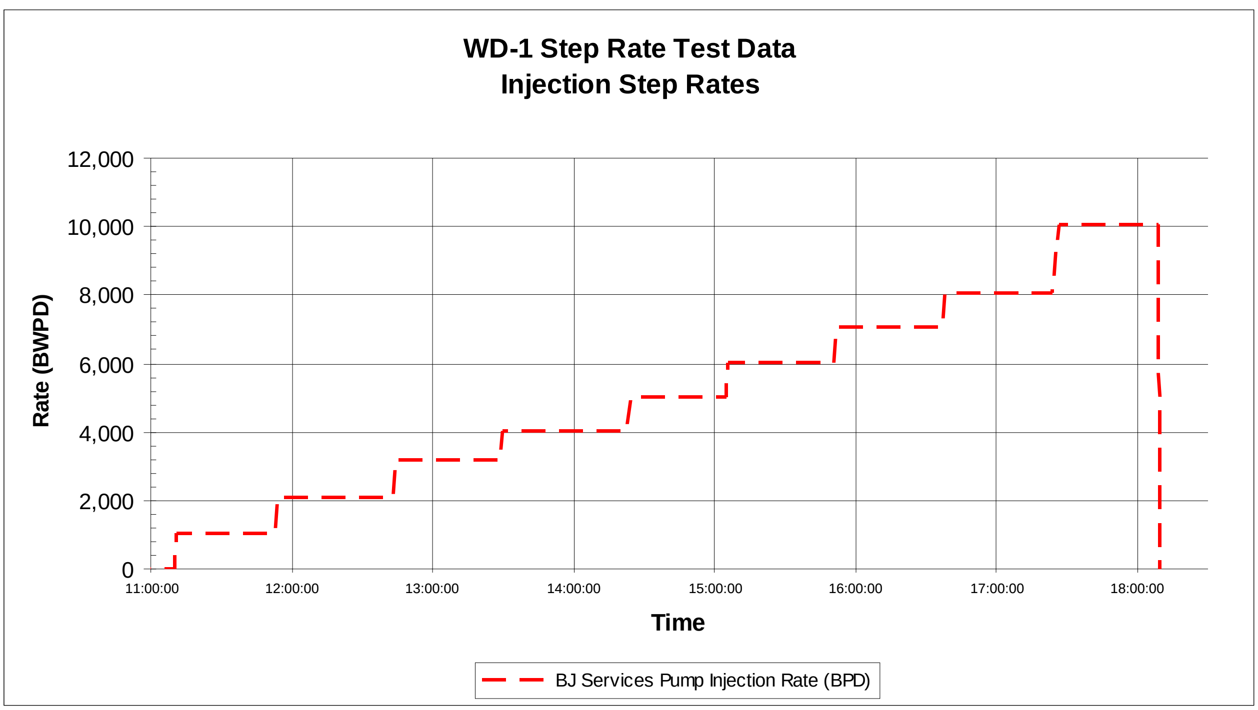
(0.4335 psi/ft for fresh water)*(1.061)*(3505 ft) = 1,612 psia hydrostatic head

Because there were no changes in the injection fluid specific gravity or temperature during the test there was no need to adjust the hydrostatic head under dynamic conditions.

Step Rates

The Step Rate Test was performed by the portable pump at the following step rates in units of barrels per minute (BPM) and then converted to barrels per day (BPD):

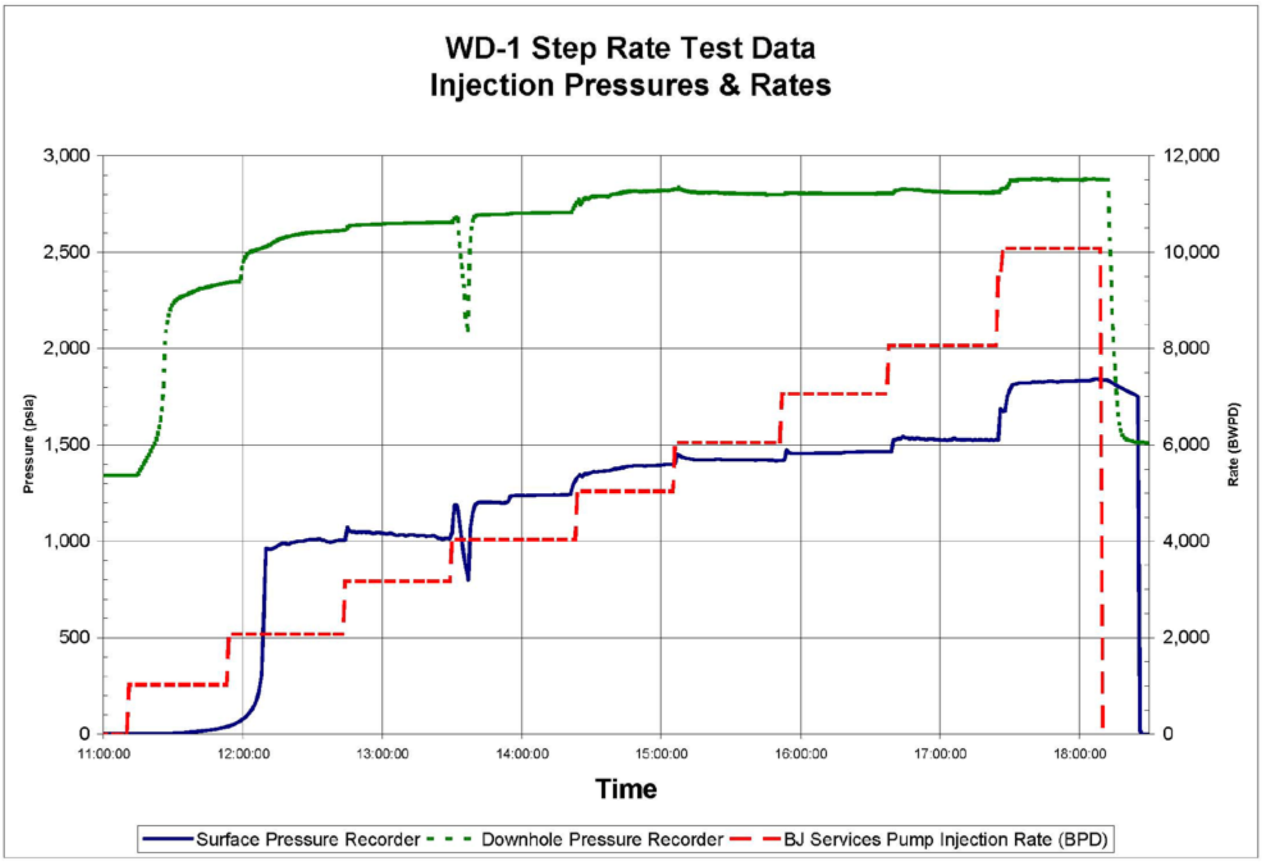
Rate BPM	Rate BPD
1.44	2,074
2.20	3,168
2.80	4,032
3.50	5,040
4.20	6,048
4.90	7,056
5.60	8,064
7.00	10,080



Correlation of Surface and Bottom-Hole Pressure Recorders

The surface pressure instrument recorded in 60 second increments while the bottom-hole pressure/temperature instrument recorded in 10 second increments. These time increments are within the individual design capabilities for the instruments.

An examination of the pressure responses indicated that the clocks in the surface and bottom-hole recorders were in sync (e.g. spikes, peaks, valleys) with less than approximately 60 seconds difference. The pressure from the two recorders are shown below along with the step injection rates:

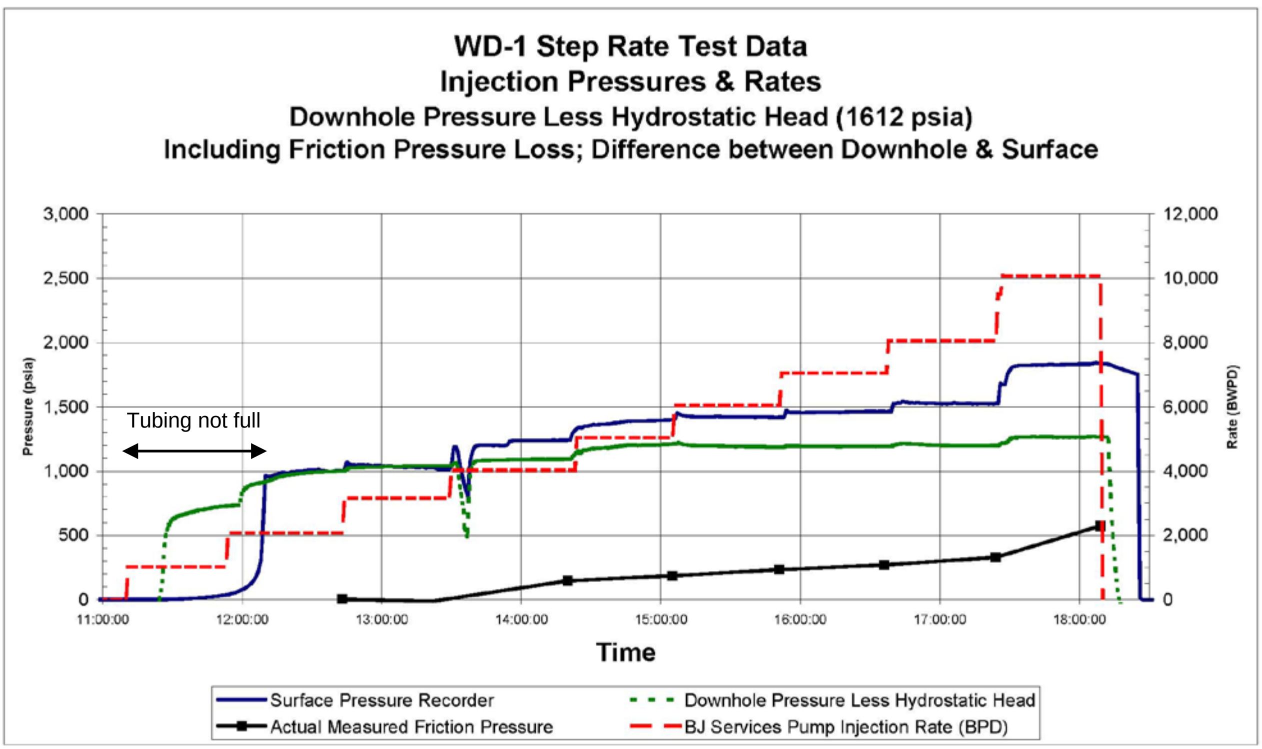


Correlation of Observed Friction Pressure Losses

To further correlate the surface and bottom-hole pressure responses the hydrostatic head pressure of 1,612 psia was added to the surface pressure. Because the Step Rate Test was started after the well had been idle for 27 hours a static fluid level in the well of about 2,917 ft existed. Thus the first few injection step rates were actually filling the tubing and charging the surrounding formation "storage" until high enough rates were achieved to create a pressure response at the surface. This effect can be seen in the early step rates.

After correcting for the hydrostatic head the remaining difference between the surface and bottom-hole pressures is the result of friction between the injection fluid and the tubing walls. Increased friction pressure losses typically increase with length of pipe, reduced diameter of pipe, increased flow rate, wall roughness, and reduced fluid temperature. Of these variables only the flow rate was changed during the Step Rate Test so all friction pressure loss can be attributed directly to flow rate. This allows for the direct measurement of the friction pressure loss specific to this wells particular mechanical condition.

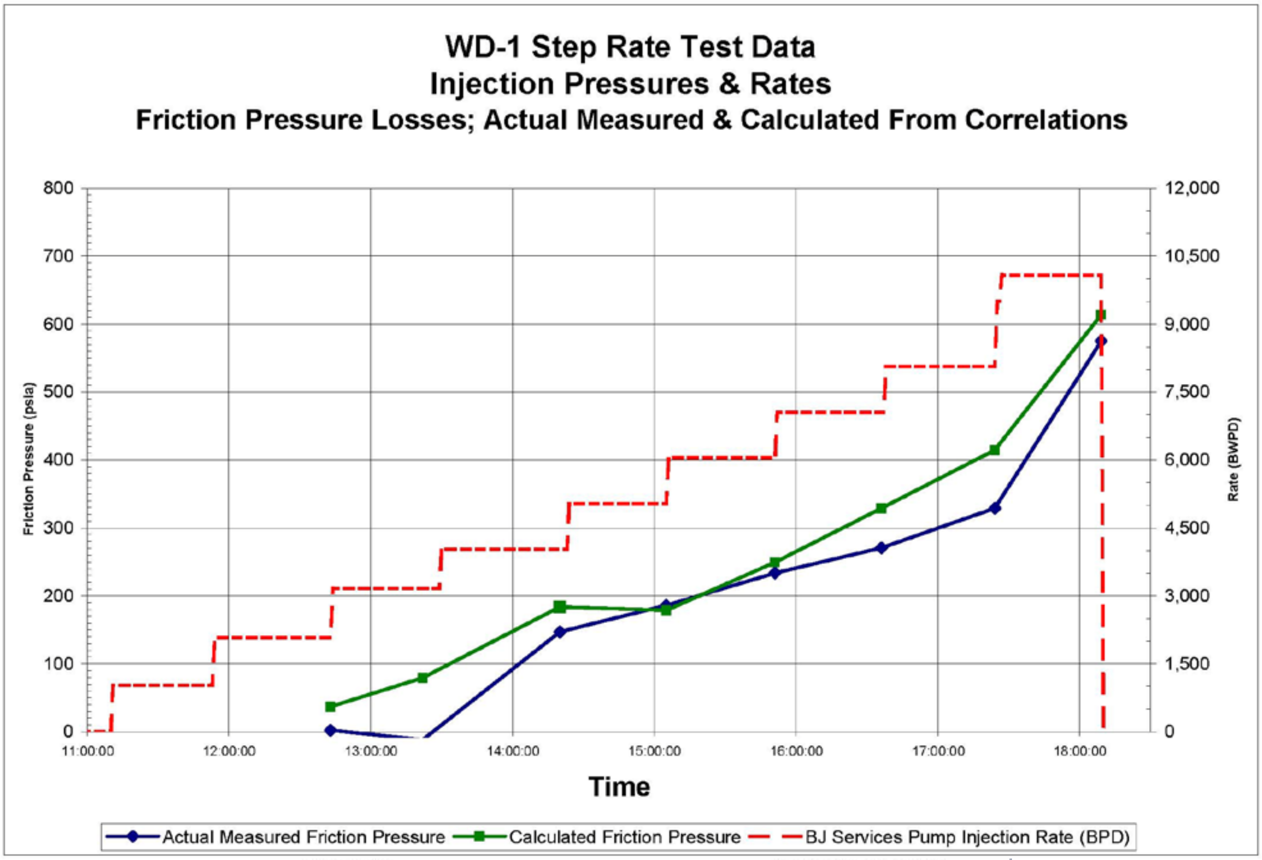
The graph below shows the surface pressure was corrected to the bottom-hole pressure using a hydrostatic head pressure of 1,612 psia. The resulting difference is the corresponding friction pressure loss at the various step rates.



Observed and Published Friction Pressure Loss Correlations

The observed friction pressure losses obtained from the test data match well with published friction correlations. These friction pressure loss correlations can be used to accurately determine the bottom-hole injection pressure at various rates using the surface injection pressure. This will allow the facility to inject water at an optimum pressure allowing for maximum rates while not exceeding the fracture pressure limitation for each zone depth.

The following graph compares the actual measured friction pressure loss with that calculated from a published friction pressure loss correlation below:



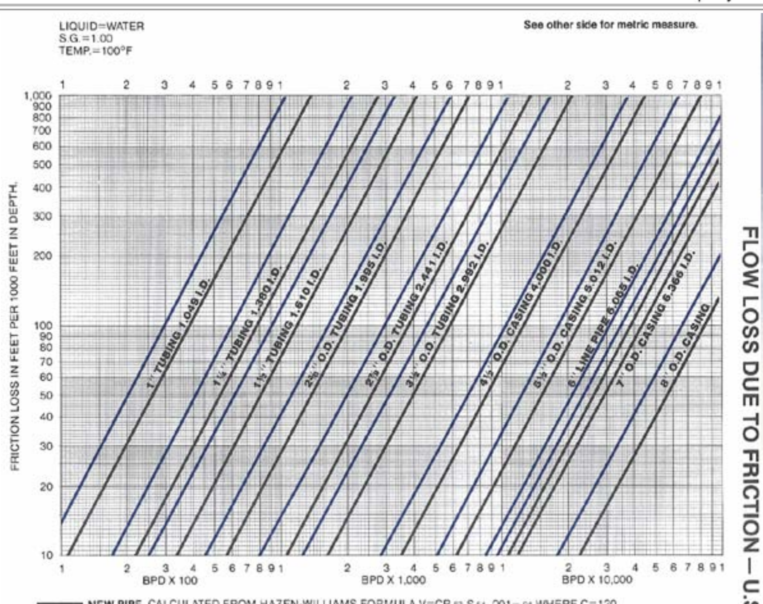


FIGURE 5. FLOW LOSSES DUE TO FRICTION IN A.P.I. PIPE (U.S.)

Actual Historic Injection Pressures (Surface and Bottom-Hole) and Profiles

Injection wells “Red Ribbon” WD-1, WD-2, WD-3 and “WI” 1 have historically been operated at surface injection pressure which cause the bottom hole pressure to remain below pressures of 0.8 psi/ft with an additional 80% safety factor applied. This has been accomplished through the application of algorithms programmed into the refinery instrumentation monitors and controls.

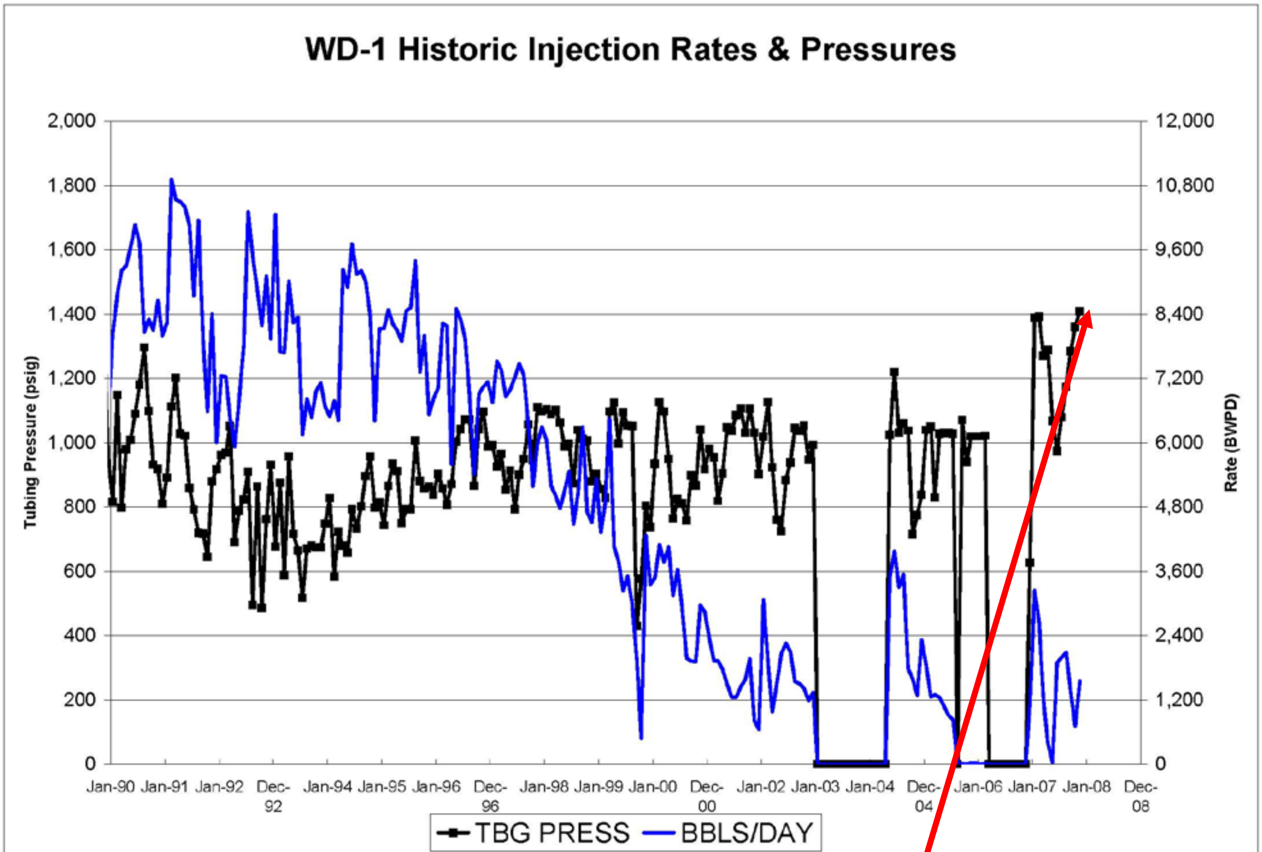
The algorithms are specific to each wells mechanical condition (diameter and length of tubing along with top perforation depth) and are used to calculate the maximum surface injection pressure at any given rate. The algorithms are based on the preceding chart for Flow Loss Due To Friction – US.

The instantaneous injection rate and pressure are continuously measured and recorded. The algorithm correlates the surface pressure to bottom-hole pressure at that given rate. Once the maximum surface injection pressure is reached for that specific rate a mechanical by-pass is automatically opened at the surface to limit the pressure to less than the maximum allowable bottom-hole pressure at that time. At any time the maximum surface pressure is reached an alarm notifies operational personnel and the incident is corrected and investigated.

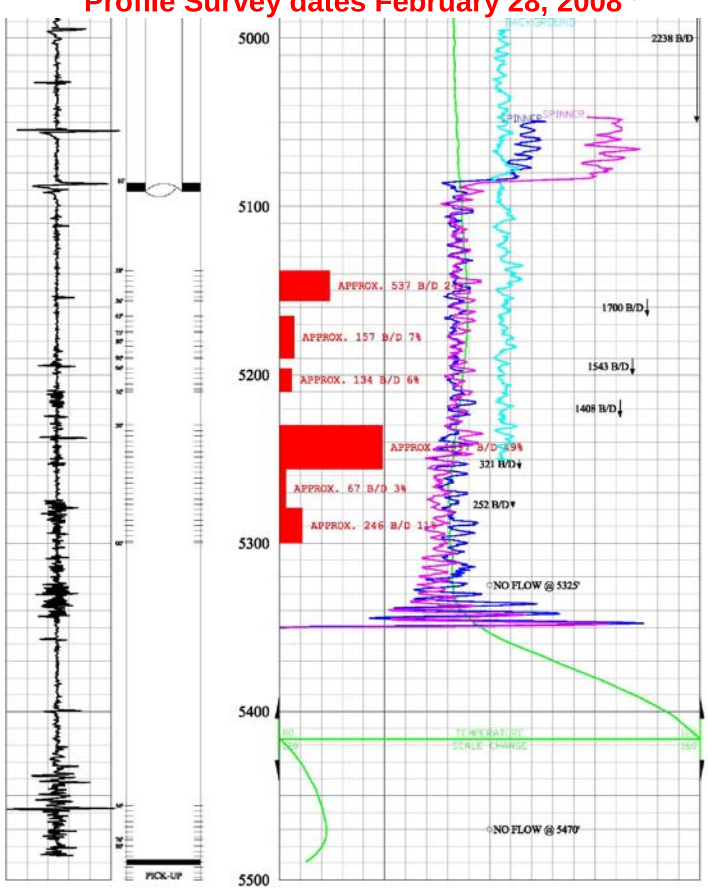
An 80% safety factor is included in the algorithm. The maximum allowable surface pressure (MASP) for each well is calculated as follows:

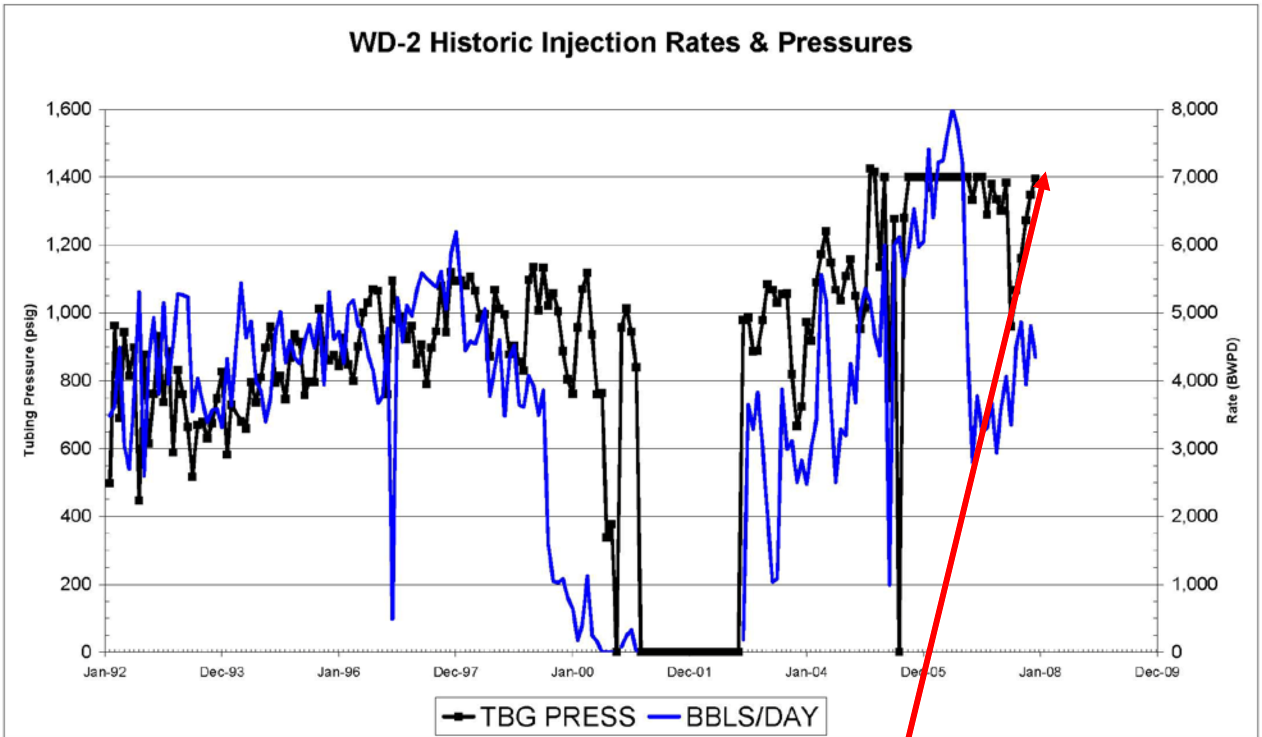
MASP = [80% * (0.80 psi/ft – 0.4335 psi/ft) * Top Perforation Depth] + Friction Pressure Loss

Annual injection profile surveys utilizing water soluble radio active tracer confirm that the historic surface injection pressures have not created bottom-hole pressures in excess of that required to induce and propagate fractures in the injection or confining zones. This is evidenced by the distributed injection profiles along with the fact that no radio active tracer has ever been detected migrating above the permitted injection zones. The historic monthly injection rates and pressures are presented for each of the four existing wells below along with a graphical summary of recent injection profile surveys for each well.

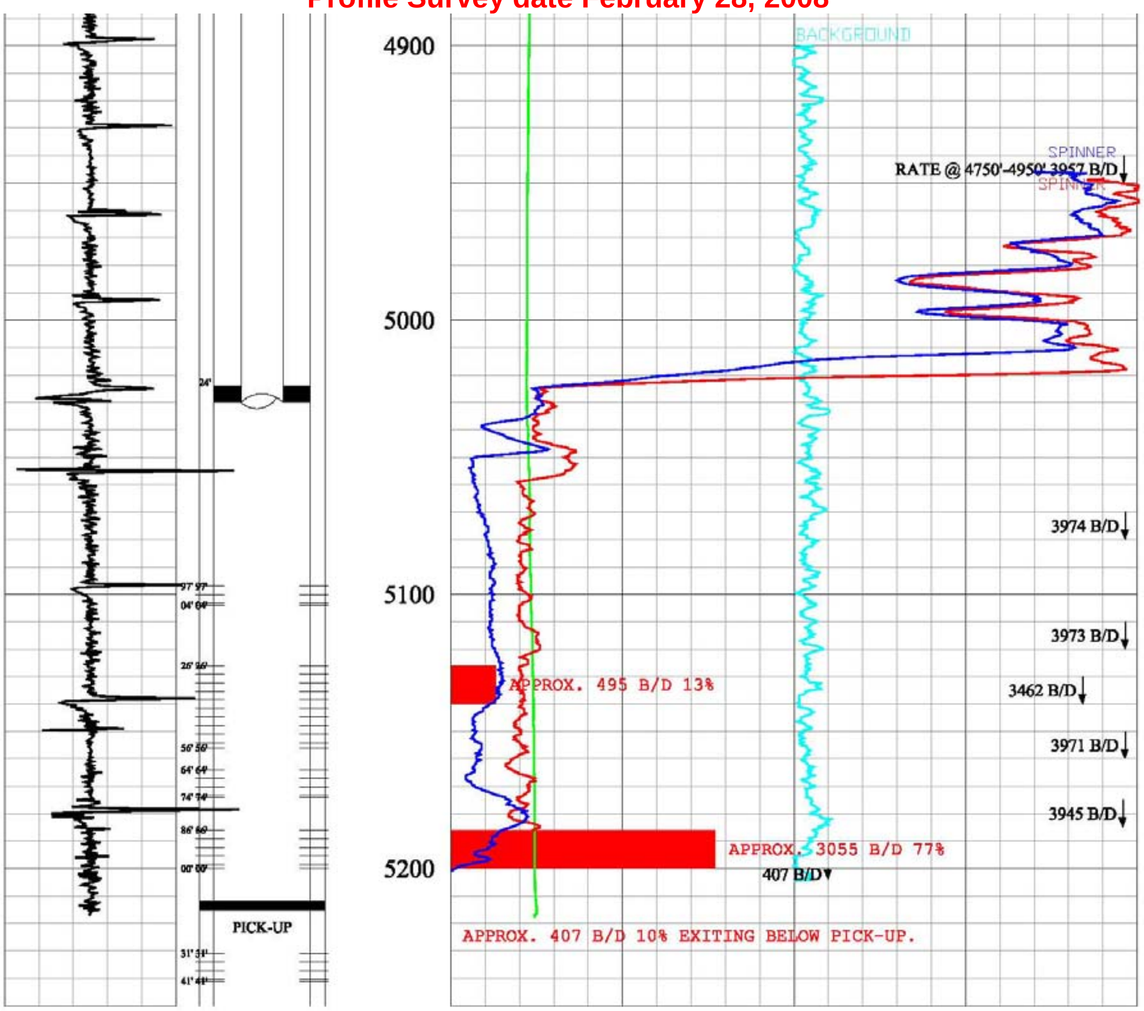


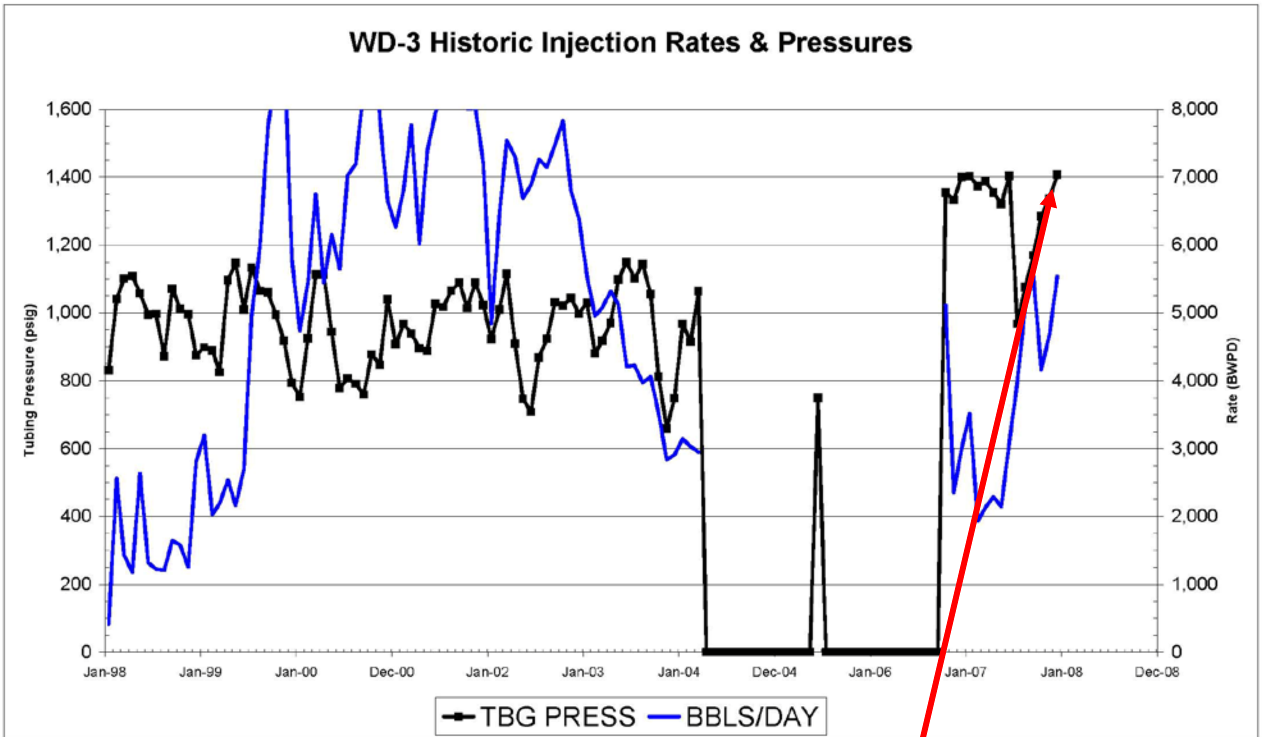
Profile Survey dates February 28, 2008



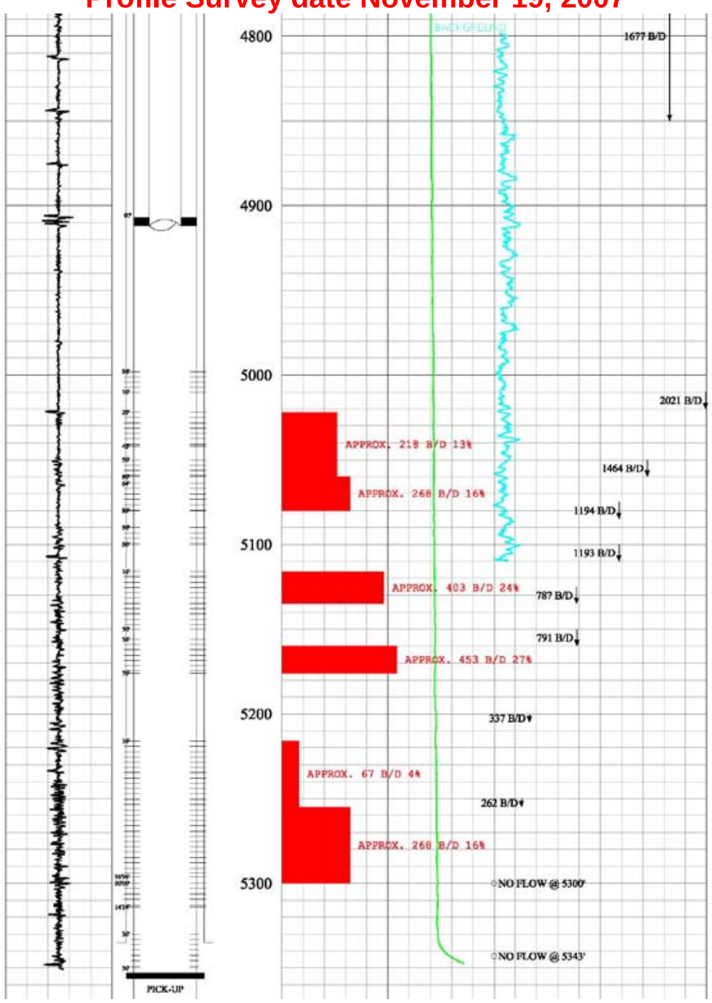


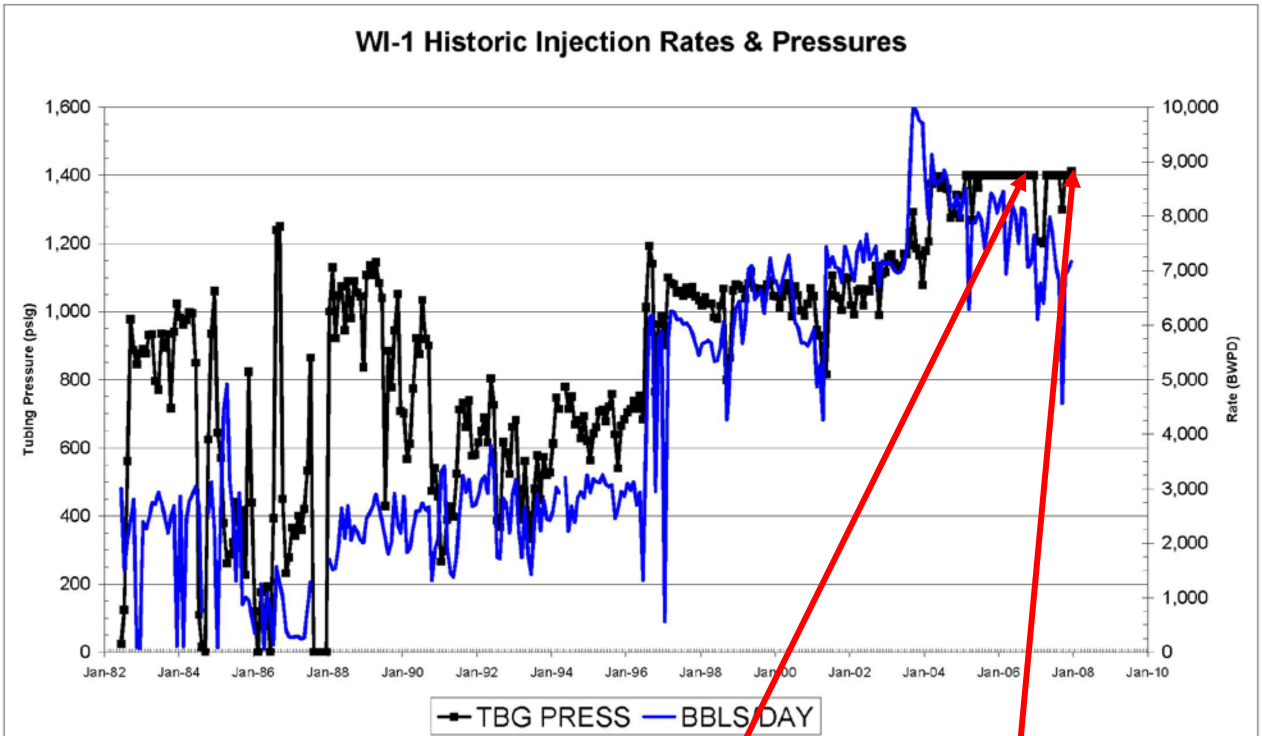
Profile Survey date February 28, 2008



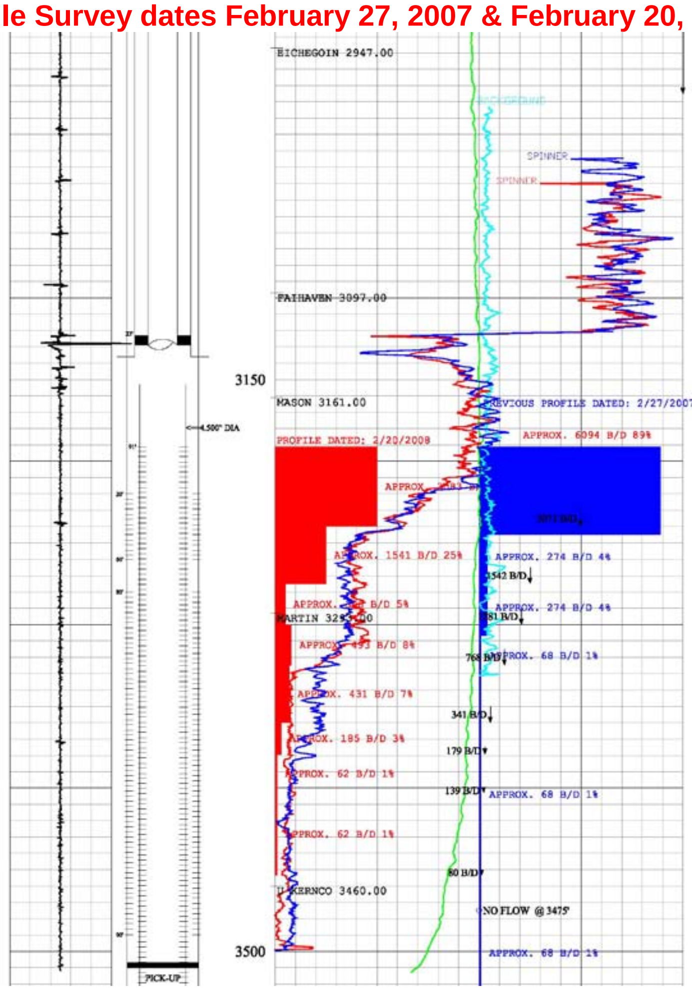


Profile Survey date November 19, 2007





Profile Survey dates February 27, 2007 & February 20, 2008



Data file disc

A disc with an Excel data file is included with this report. The file has all charts and data used in the above analyses.

AREA	OPERATOR	Well Type	Project Code	Current PAL	SUS/TER/REJ/CAN	Avg Reported Pressure	Max Reported Pressure	Fracture Gradient	Injection Zone	Location	Project Status
Main	Sunray Petroleum, Inc.	WD	25609007	31-Aug-05		800	1000	0.8	CHANAC (MIDDLE KERNCO)	28 29/27	Active
Main	San Joaquin Facilities Mgmt.	WD	25609013	10-Sep-02		900	1400	0.8	ETCHEGOIN/CHANAC	22 29/27 27 29/27	Active
Main	Big West of California, LLC	WD	25609015	11-Jun-93		800	850	0.8	ETCHEGOIN (FAIRHAVEN)	23 29/27	Active
Main	Gordon Dole	WD	25609016	18-Apr-95		250	750	0.8	ETCHEGOIN	29 29/27	Active
Main	Pace Diversified Corporation	WD	25609017	22-Mar-06		300	400	0.8	ETCHEGOIN	23 29/27 26 29/27	Active
Main	Black Gold Oil Co.	WD	25609020	10-Oct-96		0	0	0.8	CHANAC	15 29/27	Active
Main	Gordon Dole	WD	25609021	17-Sep-01		0	50	0.8	ETCHEGOIN (FAIRHAVEN)	10 29/27	Active
Main	D D Natural Resources, LLC	WD	25609022	30-Mar-05		0	700	0.8	CHANAC	29 29/27	Active
Main	San Joaquin Facilities Mgmt.	WF	25609024	12-Apr-05		1170	1500	0.8	CHANAC	27 29/27	Active
Main	Big West of California, LLC	WD	25609028	06-Jun-89		1325	1400	0.8	SANTA MARGARITA	27 29/27	Active
Main	Big West of California, LLC	WD	25609033	06-Jun-89		1400	1400	0.8	CHANAC (LOWER KERNCO)	23 29/27	Active
Main	Sunray Petroleum, Inc.	WD	25609043	09-Jul-92		900	1200	0.8	CHANAC (MARTIN,UPPER KERNCO)	27 29/27	Active
Main	Sunray Petroleum, Inc.	WD	25609045	16-Nov-92		300	500	0.8	CHANAC (PARKER,MARTIN,KERNCO)	27 29/27	Active
Main	E & B Natural Res. Mgmt. Corp.	WD	25609046	16-Aug-07		900	1200	0.8	FAIRHVEN/CHANAC (UPPER MASON)	26 29/27	Active
Main	San Joaquin Refining Co., Inc.	WD	25609049	22-Jul-91		1406	1540	0.8	CHANAC/SANTA MARGARITA	23 29/27	Active
Main	Summit Energy, LLC	WD	25609051	13-Jan-98		250	250	0.8	CHANAC-ROUND MOUNTAIN	22 29/27	Active
Main	W. A. Griffin	WD	25609118	01-May-00		1000	1000	0.8	BASAL ETCHEGOIN/CHANAC	34 29/27	Active
Main	Ancora-Verde Corp.	WD	25609030		17-Mar-72	0	0	0	ETCHEGOIN	14 29/27	C
Main	Ancora-Verde Corp.	WD	25609008	16-Oct-91	18-Jun-01	580	650	0.8	ETCHEGOIN	14 29/27	D
Main	John L. Sowers	WD	25609025	06-Oct-88	22-May-91	0	0	0.8	CHANAC (MASON-PARKER)	26 29/27	D
Main	Dole Enterprises, Inc.	WF	25609012	08-Mar-93		0	0	0.8	CHANAC (MIDDLE KERNCO)	29 29/27	S
Main	Big West of California, LLC	WD	25609019	06-Jun-89	01-Jun-06	0	0	0.8	ETCHEGOIN/CHANAC	27 29/27	S
Main	Big West of California, LLC	WD	25609026	04-Mar-97	12-Apr-01	30	30	0.8	CHANAC	22 29/27	S
Main	Summit Energy, LLC	WD	25609029	10-Oct-96	09-May-03	0	0	0.8	MARTIN/KERNCO	21 29/27	S
Calloway	S. A. Camp Companies	WD	25603001	12-Nov-92	29-Jan-99	0	0	0.8	ETCHEGOIN (MACOMA CLAY)	07 29/27	T
Calloway	Central Lease, Inc.	WD	25603002	24-Dec-91	26-Oct-93	1150	1300	0.8	ETCHEGOIN/CHANAC (42-0)	17 29/27	T
Calloway	S. A. Camp Companies	WD	25603003		17-Mar-95	0	0	0.8	ETCHEGOIN/CHANAC	08 29/27	T
Calloway	Union Oil Co. of Calif.	WD	25603005		23-Aug-83	0	0	0.8	ETCHEGOIN/CHANAC	17 29/27	T
Calloway	Norris Road Venture	WD	25603006		17-Mar-95	0	0	0.8	ETCHEGOIN/CHANAC	08/29/27	T
Main	Baker-Dickey Partnership	WD	25609006		12-Apr-95	0	0	0.8	ETCHEGOIN	21 29/27	T
Main	Texaco Ref. & Marketing Inc.	WD	25609009	06-Jun-89	04-Nov-97	0	0	0.8	ETCHEGOIN	28 29/27	T
Main	Environmental Protection Corp.	WD	25609010	07-Jul-88	02-Feb-96	0	0	0.8	ETCHEGOIN	28 29/27	T
Main	Gravelle Family Trust	WD	25609011		08-Oct-91	0	0	0.8	CHANAC (MARTIN)	23 29/27	T
Main	O. O. Co., Inc.	WD	25609014		02-Mar-93	0	0	0.8	CHANAC (KERNCO)	26 29/27	T
Main	W. A. Griffin	WD	25609018	01-Mar-93	03-Apr-01	15	15	0.8	KERNCO (UPPER)	34 29/27	T
Main	Stowe Killingsworth	WD	25609023	26-Sep-79	10-May-96	0	0	0.8	ETCHEGOIN	23 29/27	T
Main	ChevronTexaco Expl. & Prod. Co	WF	25609027		01-Jun-88	0	0	0.7	CHANAC (KERNCO)	22 29/27 27 29/27	T
Main	Petro-Lewis Corp.	WD	25609031		12-May-82	0	0	0.8	CHANAC (MIDDLE KERNCO)	29 29/27	T
Main	Thermo Flood Production Co.	WD	25609032			0	0	0	CHANAC	23 29/27	T
Main	Signal Oil & Gas Co.	WF	25609034		13-Nov-73	0	0	0	CHANAC (MARTIN,KERNCO)	23 29/27	T
Main	Crimson Resource Mgmt. Corp.	WD	25609035	17-Aug-79	06-Sep-00	0	0	0.8	CHANAC (MASON-PARKER)	15 29/27	T
Main	Ancora-Verde Corp.	WD	25609036		07-Jul-95	0	0	0.8	CHANAC (KERNCO)	16 29/27	T
Main	R. W. Henry	WD	25609037	01-Mar-93	14-Apr-00	0	155	0.8	CHANAC (MASON-PARKER)	21 29/27	T
Main	Fruitvale Properties	WD	25609038		17-Jun-91	0	0	0.8	CHANAC (MASON-PARKER)	16 29/27	T
Main	ARCO Oil & Gas Co.	WF	25609039		13-Jun-79	0	0	0	CHANAC (KERNCO)	16 29/27	T
Main	Twin Oil Production Inc.	WF	25609040		09-Sep-91	0	0	0.8	CHANAC	27 29/27	T
Main	Standing Bear Petroleum	WD	25609041			0	0	0.8	CHANAC (MARTIN,UPPER KERNCO)	27 29/27	T
Main	Standing Bear Petroleum	WF	25609042		10-Dec-91	1200	1400	0.8	CHANAC (MARTIN,UPPER KERNCO)	27 29/27	T
Main	Ancora-Verde Corp.	WD	25609044	22-Apr-92	07-Jul-95	0	0	0.8	CHANAC (MIDDLE KERNCO)	20 29/27	T
Main	San Joaquin Facilities Mgmt.	WD	25609047	06-Jun-94	26-Aug-97			0.8	MASON-PARKER	22 29/27	T
Main	San Joaquin Facilities Mgmt.	WD	25609048		10-Sep-02	500	680	0.8	ETCHEGOIN/CHANAC	22 29/27	T
Main	Ancora-Verde Corp.	AI	25609050		22-Nov-96			0.8	KERNCO	15 29/27	T